SPECIAL REPORT: U.S. Power Production Scorecard: Who Is Building New Power Plants, And Where? What Fuel Sources Will Be Used?

by Will McNamara, IssueAlert, Jan. 16 (Scientech)

[News item from Reuters] Duke/Fluor Daniel has been awarded contracts to build three natural gas-fired power plants with a combined capacity of 2,240 MW in the Western United States, Duke Energy said in a statement on Jan. 14. The projects are: the 600-MW Luna Energy Facility in Luna County, N.M.; the 620-MW Grays Harbor Energy Facility in Grays Harbor County, Wash.; and the 1,200-MW Moapa Energy Facility in Moapa County, Nev. Construction is already underway on the projects.

Analysis: This announcement from Duke Energy jumped out at me, particularly when it is placed within the broader context of a market that is not particularly supportive of unregulated power projects at this point in time. The announcement raises many questions. When so many pure-play merchant companies are canceling planned power projects in an effort to cut back capital spending and pare down debt, what factors have enabled Duke Energy to continue with these development plans, along with several others? From a broader perspective, in the shadow of claims about a national energy glut, which may or may not have a basis in reality, are there any ascertainable trends around the power projects that are proceeding? Which companies are maintaining production levels, and how are they managing their risk exposure? In which regions of the United States are the planned power projects most likely to be located? What fuel sources are most commonly used? Which factors, beyond the economic challenges unearthed by the Enron collapse, will continue to overshadow new power projects? This article will address and attempt to answer these questions.

Market Player Assessment

In the wholesale power market, the leading developers of new power plants are merchant energy companies that build power plants, the output of which is not committed to a designated customer base but rather sold on the open market, often out of the state in which the plant is located. Over the last two years, high wholesale electric prices boosted the confidence that Wall Street and creditors shared for the merchant business and their plans to add as much as 290,000 MW of generating capacity over the next six years (a 40-percent increase over the capacity of 802,000 MW for summer 2001, according to NERC). However, within the wake of the Enron collapse and softening wholesale prices, a good number of energy merchant companies (particularly those that are considered pure-play companies, or those focused singularly on the merchant business) have seen their credit ratings downgraded. Generally speaking, merchant companies depend on the ability to raise capital by selling securities, capital that is then used to support further growth through asset expansion. Most reports I've seen indicate that a new natural-gas fired combined-cycle plant costs between $500 and $600/kW or over $500 million per 1,000-MW plant. Due in part to their heavy debt loads that already exist, some of the pure-play companies faced a credit-rating downgrade that put them below investment grade. Thus, in an effort to strengthen their balance sheets and pare down debt, companies such as Mirant, Calpine and Dynegy have announced plans to scale back their once-aggressive plans to expand their generating capabilities. They may still grow, but the growth will be much more conservative and slower than previously projected.

The result is that power plants, oil and gas properties with proven reserves, and even refineries may soon go on the auction block as only those companies with strong cash resources remain heavily in the game. Consequently, I think it is no coincidence that a company such as Duke Energy is proceeding with power projects while pure-play companies are announcing cancellations. Duke Energy, an integrated company with a regulated utility that provides a steady steam of revenue, has a market capitalization of $30 billion (compared to Calpine at $4.5 billion, Mirant at $5 billion and Dynegy at $8.7 billion). The point of this? Duke has the money to spend, along with a higher credit rating than most of the pure-play merchant companies, and appears to be maximizing its opportunity to build its generation portfolio while other companies remain more stagnant or are forced to sell off assets. Duke is not the only company moving forward in the unregulated power space, but the other companies doing the same thing also tell a similar story. Constellation Energy, which had planned to spin off its unregulated power business from its regulated utility Baltimore Gas & Electric but recently announced its intent to remain integrated, just disclosed that it has over 15,000 MW of generating capacity in late-stage development, under construction, or operating across the country. FPL Energy, which owns the regulated utility Florida Power & Light, announced that it is in the process of building two natural gas-fired merchant plants, which reportedly will add about 2,324 MW to the Texas grid. Although FPL Energy's $10-billion market capitalization is small when compared to Duke, it is still larger than the average pure-play merchant company.

Thus, I conclude that integrated companies will be in a stronger financial position when compared to pure-play merchant companies, at least for the near term until the credit problems and resulting difficulties in raising capital begin to abate for the pure-play companies. As a result, I think we will continue to see a growing number of integrated companies capitalizing on their strong financial standings and leading any new generation projects that might be announced in the next few years. By the same token, we will probably see an increase in cancellation announcements from the pure-play merchant companies, who may need to terminate power projects to pare down debt.

Region Assessment

There are still plenty of regions within the United States where generation is needed, due to factors like transmission constraints and comparatively high demand growth. Within this group I would include states such as California, and possibly Pennsylvania and Texas. Note that Pennsylvania and Texas typically have had comparatively easy siting regulations, which have made it easier for companies to build new power plants in those states. The high level of interest among merchant energy companies now has caused concerns about over capacity in Pennsylvania and Texas. In California, despite recent conservation efforts in the aftermath of the state's energy crisis, demand continues to increase. However, California has had a notoriously difficult siting process for new power plants and also faces deficiencies in its transmission infrastructure, which can make it difficult for generating companies to find a suitable location for a generation facility.

Looking at the 10 NERC regions individually, we see that some regions offer greater opportunities for merchant power production than other regions. Space does not permit me to offer a thorough analysis of each region, but here are some key points that should be noted, especially regarding each particular region's reserve margin and the typical fuel sources that have been included in the region's generation portfolio. On average, reserve margins of 15 percent are considered the reliability target that most regions strive to maintain. Anything lower than that certainly indicates potential problems with deficient supply, and even reserve margins in the high teens indicate that the regions should have new power projections in construction to prepare for any decrease in reserves. Note that data regarding the individual regions' reserve margins and capacity margins were gleaned from The North American Electric Reliability Council (NERC), and are current as of October 2001. Thus, remember that NERC's projections include projects that had been announced at that point and do not include the various announcements of canceled projects that were announced in the third and fourth quarters of 2001. In addition, note that per NERC's definition reserve margins include interruptible load and capacity margins do not include interruptible load.

ECAR (East Central Reliability Coordination Agreement), which includes Indiana, Kentucky, Michigan, Ohio, West Virginia, and portions of Virginia and Pennsylvania: This region reportedly has the third-largest generation fleet of almost 110,000 MW, comprised mostly of baseload coal-fired generation but lacking in peaking-generation capacity. For summer 2001, reserve margins in ECAR were 17 percent and capacity margins were 15 percent. However, projections for summer 2005 indicate a decrease in this region, with reserve margins falling to 11.1 percent and capacity margins falling to 10 percent.

ERCOT (Electric Reliability Council of Texas), which covers most of Texas, including Dallas, Houston and coastal areas: Texas is mostly composed of baseload natural gas-fired generation and has a significant natural-gas peaking capacity. For summer 2001, reserve margins in ERCOT were 30 percent and capacity margins were 23 percent. Projections for summer 2005 include reserve margins of 35 percent and capacity margins of 26 percent.

FRCC (Florida Reliability Coordinating Council), which covers all but the western panhandle of the state of Florida: The second-smallest region under NERC. Most of FRCC is composed of baseload coal-fired, nuclear and oil-fired generation. Per state regulatory restrictions, it is very difficult for an out-of-state company to build a merchant plant in Florida, although some companies have been successful in building peaking units. For summer 2001, reserve margins were 21 percent, and capacity margins were 17.2 percent. Projections for summer 2005 include reserve margins of 23.1 percent and capacity margins of 19 percent.

MAAC (the Mid-Atlantic area), which covers Delaware, New Jersey and all but the western portions of Maryland and Pennsylvania: This region is considered one of the most populous, but is slow growing due to its maturity. MAAC's portfolio consists mostly of baseload nuclear, coal and oil-fired generation and the region. For summer 2001, reserve margins were 18.1 percent and capacity margins were 15.4 percent. Projections for summer 2005 include reserve margins of 52.3 percent and capacity margins of 34.3 percent.

MAIN (the Mid-America Interconnected Network), which includes Illinois and portions of eastern Wisconsin and Missouri: This is considered a mid-sized region with regard to capacity (reportedly about 55,000 MW), including mostly baseload coal-fired and nuclear generation. For summer 2001, reserve margins were 24 percent and capacity margins were 19.2 percent. Projections for summer 2005 include reserve margins of 27.4 percent and capacity margins of 22 percent.

MAPP (the Mid-Continent Area Power Pool), which covers the states of Minnesota, North Dakota, South Dakota, western Iowa, Nebraska, western Wisconsin, and northeastern Montana): Most of the region consists of baseload coal-fired generation. For summer 2001, reserve margins were 22.2 percent and capacity margins were 18.2 percent. Projections for summer 2005 include reserve margins of 15.1 percent and capacity margins of 13.1 percent.

NPCC (the Northeast Power Coordinating Council), which covers the states of Connecticut, New York, Rhode Island, Massachusetts, Vermont, New Hampshire, and Maine. Note that NPCC includes the sub-regions of NEPOOL and NYPP, which may require their own assessment. The region is mostly composed of baseload nuclear, coal, hydro, and oil-fired generation. For summer 2001, reserve margins were 17 percent and capacity margins were 14.4 percent. Projections for summer 2005 include reserve margins of 28.2 percent and capacity margins of 22 percent.

SERC (the Southeastern Electric Reliability Council), which includes the states of Georgia, Alabama, Mississippi, South Carolina, North Carolina, Tennessee, and small parts of Florida, Kentucky and Texas: Note that SERC includes four regions of Entergy, Southern, TVA, and VACAR, which may require their own assessments. The region's portfolio consists mostly of baseload nuclear, coal and gas-fired generation. For summer 2001, reserve margins were 12 percent and capacity margins were 11 percent. Projections for summer 2005 include reserve margins of 15 percent and capacity margins of 13 percent.

SPP (Southwest Power Pool), which includes Kansas and portions of Arkansas, Oklahoma, Louisiana, Texas, New Mexico, and Missouri: Projections suggest that this region's generation portfolio will remain a mix of mostly natural gas, followed by coal. For summer 2001, reserve margins were 18 percent and capacity margins were 15.3 percent. Projections for summer 2005 include reserve margins of 13 percent and capacity margins of 11.3 percent.

WSCC (Western Systems Coordinating Council): Note that the WSCC, which covers the largest land area in NERC, includes four sub-regions including the Arizona-New Mexico-Nevada, California, Northwest, and Rocky Mountain regions, which might require their own assessments. The region's generating portfolio is mostly based in natural gas, but also includes hydroelectric and wind resources. For summer 2001, reserve margins were 21.1 percent and capacity margins were 18 percent. Projections for summer 2005 include reserve margins of 46.4 percent and reserve margins of 31.7 percent.

Some other information that I found pertinent is that the Northwest power spot market reportedly has so much excess generating capacity right now that unplanned outages of two large 700 MW generators didn't even budge prices. However, the Northwest's appetite for natural gas continues to increase, and nine new plants that recently have been completed or are under construction in Oregon, Washington and Idaho are all fueled by natural gas. Wind power in the region, which is being used as a supplement so that the more common hydroelectric power in the region can be stored, is also becoming popular but the increase of natural-gas generation in the area has been particularly strong.

Fuel Source Assessment

There is little doubt that natural gas remains the fuel of choice for most new power plant projects. In fact, of the nearly 300,000 MW of the projects announced over the course of 2001, over 90 percent were to be fired by natural gas. However, this represents some serious considerations for the merchant energy business, considering that natural-gas supplies are not infinite. Incremental natural-gas supply growth has reportedly leveled off at about less than 1 percent annually despite record levels of drilling activity. Unless unprecedented amounts of new net-gas production emerges over the next three to five years, it is arguable that only a fraction of the currently planned gas-fired generation (perhaps less than 40 percent) will actually be constructed. The good news is that storage volumes of natural gas have increased over the last year. According to the Energy Information Administration (EIA), by Nov. 1, 2001, working gas stocks were estimated to have reached more than 3,100 billion cubic feet. However, if we consider that about 91,000 MW of planned projects had been canceled at the end of 2001, about 200,000 MW of planned projects remain on the drawing boards. The obvious question is where the natural gas needed to fuel these projects will come from, and whether or not other fuel sources will be available to supplement what appears to be a natural-gas shortage in the long-term.

Over the course of 2001, over 60 new power projects using coal-fired generation were announced. Most of these projects are in the early stage (study/initial permitting). When we consider that there were very few coal power-plant announcements in the past 15 years, this is a considerable development that indicates the renewed interest in coal-fired generation.

It is also important to note that, according to some wind-power representatives, the U.S. wind-energy industry installed nearly 1,700 MW or $1.7 billion worth of new generating equipment in 16 states in 2001. This marked the wind industry's most productive year, and more than doubled the final tally of 732 MW that was installed in 2000. However, the wind market could face a set back if the 1.5 cents/kWh federal tax credit is not renewed soon.

Again, I refer back to Duke Energy. Rick Priory, the company's CEO made a decided effort several years ago to converge natural gas and power around physical assets to support Duke's trading business. In other words, because Duke has diversified physical assets, it can hedge its risk depending on pricing trends for natural gas or power.

Remaining Risks

In October 2001, NERC released its 10-year reliability assessment, in which it forecast that electricity-generation capacity will expand faster than demand during the next decade. Specifically, NERC projected that about half of some 245,000 MW of proposed new merchant-generating capacity would come online by 2005, far outstripping a projected 63,800 MW increase in electricity demand. Beyond 2005, NERC said it was more difficult to project capacity margins but expressed confidence that the excess margins would continue. Of course, NERC's report was released before the collective scale-back of power projects among pure-play merchant companies such as Mirant, Dynegy and Calpine. Consequently, the specific claims of new generating capacity may need to be tweaked a bit, particularly over the next five years. Nevertheless, some market risks facing merchant companies remain in effect. They include the ability to obtain necessary siting and environmental permits, the ability to obtain financial backing, and the ongoing volatility of fuel prices and supply trends. In addition, the ongoing national deficiency of transmission infrastructure, which is more acute in some areas than others, remains a market challenge. NERC forecast that power-grid congestion will get worse over the next 10 years as very little new transmission will be added during the next decade. This will impact merchant companies as constraints will remain on the transmission capacity that is available to transport power, which might curtail power sale transactions.

In addition, falling wholesale prices are certainly another risk factor that unregulated power-producing companies will have to face. Wholesale electricity for summer 2002 delivery to Palo Verde, Ariz. (the Western region's key summer hub) has slumped to about $45/MWh from about $75/MWh in the summer of 2001. In addition, the EIA has projected that wholesale natural-gas prices will remain between $2 and $3 per MMBtu until the spring of 2002, which compares to $5 per MMBtu and shot up to $10 last year. This data is supported by information from the Henry Hub exchange.

Moreover, the next few years may represent fewer announcements for new power plants for the merchant-power business, especially when compared to the 1999-2000 period, or the aggressive proposals that were unveiled in 2001. As most data suggest that electricity demand will continue to increase at a rate of about 2 percent over the next five years, the general consensus is that in most parts of the country existing supply or generating sources that are currently under construction should be sufficient to meet demand. The caveat to this statement is that, as noted, some states in particular (such as California, Florida and New York) may continue to have demand growth that outpaces supply, and therefore new power-generation construction plans could be focused on those regions. After the 2003-2004 period, the excess capacity across the country, if it indeed exists, should level off, meaning that new generation projects should once again gain momentum. Also, if a sudden increase in demand nationwide occurs, perhaps related to unusual weather trends, that could also prompt a new cycle of generation expansion. A lot of this is of course based on speculation, but the general forecast for 2002 at least is still rather bearish when it comes to the amount of power projects that will be announced or pursued.

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